April 29, 1997

VIA UPS Next Day Air

Docket Office
California Public Utilities Commission
505 Van Ness Avenue, Room 5113
San Francisco, CA 94102

Re: A.96-12-009, A.96-12-011, and A.96-12-019

Dear Docket Clerk:

Enclosed for filing in the above-entitled matter are the original and five copies of the **OPENINGBRIEFOFTHECALIFORNIAENERGYCOMMISSION**. As request by Judge Weissman, all parties who have requested e-mail service, have been sent an e-mail version of the brief in addition to official service by mail. Please return the extra copy in the enclosed, stamped, self-addressed envelope. Thank you for your attention to this matter.

Very truly yours,

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Enclosures

cc: Judge Weissman (VIA UPS Next Day Air)
A.96-12-009, A.96-12-011, and A.96-12-019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY To Identify And Separate Components of Electric Rates, Effective January 1, 1998. (U-39 E)	Application 96-12-009 (Filed December 6, 1996)
Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M) For Authority To Unbundle Rates and Products.	Application 96-12-011 (Filed December 6, 1996)
In the Matter Of The Application Of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) Proposing The Functional Separation Of Cost Components For Energy, Transmission and Ancillary Services, Distribution, Public Benefit Programs And Nuclear Decommissioning, To Be Effective January 1, 1998 In Conformance With D.95-12-036 As Modified by D.96-01-009, the June 21, 1996 Ruling of Assigned Commissioner Duque, Decision 96-10-074, and Assembly Bill 1890.	Application 96-12-019 (Filed December 6, 1996)

OPENING BRIEF OF THE CALIFORNIA ENERGY COMMISSION

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I. INTRODUCTION

The California Energy Commission (CEC) hereby submits its opening brief following evidentiary hearings in the above-referenced rate unbundling proceeding. This is the first opportunity for the California Public Utilities Commission (CPUC) to consider rate design implementation issues in the restructured environment. Electric industry restructuring, however, remains a work in progress. This is just the first step. Many further steps will be required during the four-year transition period to achieve electric utility rates that are appropriate for the disagregated utility distribution company (UDC) to which today's vertically integrated utilities will evolve.

Nevertheless, it is essential for certain rate design features to be in place beginning January 1, 1998. Those include:

(1) hourly rate options for both direct and virtual direct access customers, which create an incentive for real-time metered customers to use energy during lower cost hours of the day and eliminate the incentive for direct access customers to use energy during high cost hours of the day, must be available. These hourly rate options can be designed to facilitate competition transition charge (CTC) recovery during the transition period;

(2) during the transition period while CTC is collected, the CPUC should set a default energy price whenever the Power Exchange (PX) is in an "over generation" condition. This condition occurs when demand in the PX is fully met by "must take" energy through contracts with qualifying facilities (QFs);

(3) the CTC should be allocated to energy costs and reflected as energy costs on customers bills, and the 10% rate reduction applicable to residential and small commercial customers, should be treated and reflected on customer bills as a reduction of CTC, to the extent possible;

(4) generation-related costs, such as estimating UDC customer hourly loads and UDC load bidding into the PX on behalf of UDC energy customers must be classified as generation and not be collected in the distribution charge;

(5) the utilities should develop a load forecasting methodology on behalf of UDC customers that is based on the energy use of its own customers, rather than a subtractive "net" approach that could result in over-allocation of load forecasting errors to UDC customers;

(6) customer bills must include the following information beginning in January 1, 1998:

a. energy charges separately identifying: PX energy charges, the imbalance settlement costs, the UDC energy charges, the CTC charges and nuclear decommissioning charge;
b. transmission charge;
c. distribution charge;
d. non-bypassable surcharges; and
e. other information including: average peak and off-peak energy prices; self-comparison and other-customer comparison information.

(7) if UDC consolidated billing is going to be available to private energy services providers (ESPs) beginning January 1, 1998, the CPUC must determine the terms and conditions for each utility.

Rate design features that can be deferred beyond January 1, 1998, but that must be in place and reflected in rates on or before conclusion of the transition period include the following:

(1) the monopoly functions of the UDC must be defined and a separate revenue requirement must be developed based on the costs of providing those

services;

(2) the functions that the UDC performs only on behalf of UDC energy customers (full-service customers) must be defined separately from the functions the UDC provides on behalf of all distribution customers with a separate revenue requirement and separate ratemaking treatment for these services;

(3) the optional non-monopoly services offered by the UDC must be defined and the costs of each service offering must be determined and priced separately from other UDC services on customer bills;

(4) new distribution performance-based ratemaking (PBR) proceedings should be initiated for each utility to accomplish the foregoing and to put in place a PBR structure that accommodates UDC provision of monopoly and non-monopoly services, ensures against cross-subsidization and provides incentives for UDCs to develop accurate load bids on behalf of UDC energy services customers;

(5) the CPUC should acknowledge that load-profiling is not just a direct access issue and direct the utilities to develop accurate dynamic load profiles for homogenous customer groups that will be used to develop more accurate load forecasting for UDC and ESP customers without real-time meters;

(6) the CPUC should take the opportunity to seek legislative approval to redesign how to provide affordable electricity to residential customers so that rates for all customers can be consistent with economic efficiency.

II SCOPE AND OBJECTIVES OF PROCEEDING

A. Utility and non-Utility Characterization

The record as a whole reveals disagreement among the parties as to the scope and objectives of this proceeding. On the one hand, utilities take a narrow view based on the premise that utilities' most recently authorized revenue requirements will remain unchanged and the only objective of this proceeding is to divide the existing revenue requirement among the three functional areas, generation (G), transmission (T) and distribution (D), allocate these functional cost breakdowns to customer classes, and develop final tariffs. Utilities have not determined whether any traditional utility functions may no longer be necessary, or may be provided by nonregulated firms, or whether restructuring will entail new and/or different activities, and if so, what those new activities may cost and how these costs should be recovered. (See CEC Direct Testimony (Test.) at pp. 18-20, witness Kristov, for a general description of each applicant's approach.) Parties referred to the utilities' approach variously as "tops-down," "residual" or "subtractive."

The non-utility parties, on the other hand, generally take a broader view that takes into consideration the reality that the existing utilities will evolve into UDCs that: (1) no longer perform some traditional utility functions (either because they will be performed by the Power Exchange (PX) or the Independent System Operation (ISO) or because they simply will no longer be needed and therefore, not performed at all); (2) may perform new functions; (3) will perform some functions on behalf of all customers interconnected with the distribution system (e.g. the wires related-activities); (4) will perform other functions only on behalf of customers who receive their energy requirements from the PX (e.g. load bidding and forecasting); (5) will perform still other functions that may also become available from private suppliers (e.g. metering); and (6) require separate rate-making treatment based on the costs of providing the various services. Parties to the proceeding generally referred to this approach as a "bottoms up" approach.

Non-utility parties expect the future UDCs to be smaller and more efficient compared with today's utilities, with a smaller proportional revenue requirement. Utilities appear to have little vision (or are unwilling to discuss what vision they may have) of what their utilities will evolve into. (Transcript (Tr.), Volume (Vol.) 2 at p. 280, l. 1-p. 282, l. 10, Southern California Edison (SCE) witness Fielder); Tr., Vol. 3 at p. 301, ll. 1-14, Pacific Gas & Electric Co. (PG&E) witness McCarty; Tr., Vol. 3 at p. 367, l. 20-p. 369, l. 7, San Diego Gas & Electric Co. (SDG&E) witness Hansen). Nevertheless, at least one utility representative from SCE, testified that the UDC will continue to offer the same level of customer services as the vertically-integrated utility offers today. (Tr. Vol. 6 at p. 757, l. 25-p. 760, l.4, SCE witness Ziegler).

B. CPUC Guidance

More importantly, the utilities have not identified the cost categories that are included in the current revenue requirements as required by Commissioner Duque's May 8, 1996 and Administrative Judge Weissman's January 31, 1997 rulings. Commissioner Duque provides the following guidance to the utilities with respect to separating the utility function into G, T and D:

> Because the accounting definitions vary across utilities and some accounts include costs for more than one functional area, the first step in unbundling costs requires the functional identification of each cost category and account. This identification allows the completion of the next step of assigning these costs to one of the three functional areas of generation, transmission and distribution.

(Assigned Commissioner Ruling of May 8, 1996 at p. 6.) In other words, before a cost can be assigned to a broad functional area (G, T or D), the cost, and the utility activity, or function, associated with that cost, must be separately identified. Only then can assignments to functional areas be made. This instruction is echoed in Judge

Weissman's ruling in which he instructs the parties that

> we will be examining the functions related to the costs contained within a broader category to determine whether or not they have been assigned to the appropriate area. For instance, each utility will be required to demonstrate that costs assigned to a broad area such as Distribution are appropriately derived from distribution-related functions. It is not sufficient to suggest that a category such as Distribution can be determined on a residual basis. Each dollar must be related to and reasonable in light of a category of activity or expense that is clearly a part of the broader functional area.

(Administrative Law Judge's Ruling on Schedule, Scope, and Other procedural Matters of January 31, 1997 at 2).

Commissioner Duque's May 8, 1996 ruling also notes that certain utility functions, such as administrative and general (A&G), customer service and support, meter reading and billing, among others, do not have a "unique relationship" to G, T or D and requested parties to consider how to allocate them across G, T and D. (Assigned Commissioner Ruling of May 8, 1996 at p. 6.) In D. 96-10-074, the CPUC notes that in response to this request, parties proposed to include some of these functions as distribution costs, i.e. and not allocate them among G, T and D as suggested by Commissioner Duque. (D. 96-10-074 at p. 9.) The CPUC notes its concerns with the utilities' approach and agreed with Commissioner Duque's distinction that activities that do not have a "unique relationship" to G, T or D be allocated among these functions. (Id.) The CPUC also advises that requiring utilities to separately identify costs that may fall within a broad functional area is not the same thing as unbundling the distribution function (even though this activity may be a prerequisite for distribution unbundling).[1] (Id.)

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[1] The CEC has long advocated that "unbundling" be recognized as containing two elements: separation of components for transparency of costs and to permit optional levels of service, ar opening some components of service to competitive supply. (CEC Comments of September

Although these rulings may not go as far as some non-utility parties would like, (the rulings do not require the utilities to identify new activities that they must perform, for example), the utilities' applications and supporting testimony fall far short of the showing required. Instead, the utilities appear to rely on D. 96-10-074, in which Ordering Paragraph No. 1 requires PG&E, SCE and SDG&E to

> file their total ratebase and base revenue requirement **based** on our last authorization and should separate this total between transmission and distribution . . . .

(Id. at p.20 (emphasis added).) The text of the decision further requires utilities to

> include clear explanations for any changes since last authorized and explain rules used to allocate this ratebase and revenue requirement between transmission and distribution.

(Id. at 9-10, see also Ordering Paragraph 1.) D. 96-10-074 simply requires the utilities to file their cost separation **based** on their most recent revenue requirement; nothing in this decision supports the conclusion that the revenue requirement cannot change in the course of this proceeding. Indeed, the text of the decision contemplates the possibility that the utilities' applications themselves might include requests for changes.

C. The Solution

Since AB 1890 caps rates at June 10, 1996 levels (except for residential and small commercial customers who will receive a 10 % rate reduction) it is not essential to finally determine the appropriate revenue requirement for the distribution function

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1996 on Ratesetting Working Group Report Unbundling Report at pp. 5-6.)

before January 1, 1998 for rates that will be in effect on January 1, 1998. The transition period affords the CPUC and the parties the opportunity to engage in the process out-lined by Commissioner Duque and Judge Weissman. The first step is to identify all utility activities and the costs associated with those activities.

The next step is to identify which of these activities will be performed by the UDC on January 1, 1998. Costs attributable to activities that will no longer be performed by the UDC should be removed from the UDC revenue requirement. Costs for activities that the UDC will be performing can be reviewed and the revenue requirement adjusted accordingly. The distribution revenue requirement could then be set retroactively to January 1, 1998, without affecting rates, just the accounting treatment of the revenues collected. For example, if the revenue requirement goes down, more dollars will be available to offset CTC.

Nevertheless, it is necessary to determine now what new or different activities the UDC will be performing that relate to the generation function, such as PX load forecasting and load bidding. These costs must be identified before January 1, 1998 so that they can be removed from the distribution rates charged to all distribution customers.[2] Only UDC energy customers should bear these costs; direct access customers should not bear these costs. The energy credit reflected in what the direct access customer sees on his bill should include these generation-related costs in addition to the actual PX charges to the UDC for energy bids and other PX support costs.

Finally, the CPUC must also take the further step of defining the UDC function for the post-transition era for rates that become effective in 2002, or earlier if CTC has been fully collected. This involves: (1) defining the monopoly functions of the UDC that all

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[2] In addition, the CPUC must resolve whether the utilities are entitled to increase the distributi revenue requirement in the event the Federal Energy Regulatory Commission (FERC) approve transmission rates that are lower than those requested by utilities in their March 31, 1997 filing The record on this issue is fully developed and of great interest to many intervenors.

distribution customers benefit from and developing a new revenue requirement based on the costs of providing those services; (2) defining the functions that the UDC performs only on behalf of UDC energy customers and developing a revenue requirement based on the costs of providing those services; (3) defining and separately identifying non-monopoly services and the associated costs of each service offered by the UDC; and (4) establishing a new distribution PBR for each utility to accomplish the foregoing and to put in place a structure that accommodates UDC provision of monopoly and non-monopoly services including ensuring against cross-subsidization and incentives for UDCs to develop accurate load bids on behalf of UDC energy services customers.

III. REVENUE REQUIREMENTS AND COST RECOVERY ISSUES

A. Comments Common to All Applicants

Subsections 1- 2 concern revenue requirements and cost recovery issues that must be resolved before January 1, 1998. Subsections 3-5 may be deferred, as suggested above, but must be resolved before the end of the transition period.

1. Generation Related Costs Must Be Identified, Removed From Distribution and Charged Only to UDC Energy Customers.[3]

The record in this proceeding demonstrates that there are energy-related costs that the UDC will incur to serve customers with PX energy. Those costs include: preparation of estimates of hourly loads for UDC generation service customers and

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[3] To the extent this section proposes to allocate generation-related costs to generation, this is could also be discussed in Section IV, Rate Design and Cost Allocation. Since this issue is a discussed generally in Section II, Scope and Objectives, and to some extent in Section VI, Bill Formats, this issue will not be revisited in Section IV.

bidding that load into the PX. (CEC Direct Test., Exh. 56 at p. 25, ll. 3-9, witness Jaske.) Dr. Jazayeri, for example, acknowledges that SCE had not determined what it would cost to perform PX-related activities, because "the protocols are not still sufficiently developed to allow us to determine what are the requirements and what the appropriate costs would be." (Tr. Vol. 11 at p. 1465, ll. 24-28, witness Jazayeri.) Nor has SCE determined how these costs should be recovered, but agreed that they should not be recovered from direct access customers. (Id. at p. 1466, ll. 1-26.)

Indeed, those protocols for developing load forecasts that Dr. Jazayeri referred to must be developed. The CEC maintains that the UDC must develop its own load forecasts based on the usage patterns of UDC energy customers. (CEC Direct Test., Exh. 56 at p. 31, l. 18-p. 34, l.5, witness Jaske.) Similarly, ESPs must be responsible for developing their own load forecasts. The accuracy of the load forecasts will have a direct impact on energy imbalance settlement costs. Costs incurred as a result of UDC forecast errors should not be passed on to private ESPs or their customers; costs incurred by forecast errors of private ESPs should not be passed on to the UDC or its customers. The UDCs and the ESPs must have a sufficient incentive to ensure that imbalances are fairly allocated to PX/UDC energy customers. (Id.) The costs associated with developing a load-forecasting methodology should be tracked and recovered only from UDC energy services customers.

The Utility Reform Network (formerly known as Toward Utility Rate Normalization) (TURN) and the Utility Consumers Action Network (UCAN) identify other existing costs that should be removed, at least in part, from distribution rates including costs associated with marketing, customer information services and greater proportion of A&G and common plant costs than the utilities propose. (TURN/UCAN Direct. Test., Exh. 63 at pp. 7-14.) The CPUC must take a close look at these costs and allocate them in an equitable manner between G, T and D, bearing in mind that each income producing activity of an enterprise is expected to generate sufficient income to cover the variable costs of that activity and a portion of fixed costs not directly assignable to that activity. (Tr. Vol. 15, pp. 1843-1845, witness Yap.)

As a related matter, TURN/UCAN also identify traditional generation-related costs, such as plant dispatch and power purchasing, that will no longer be incurred by the utility, but will be subsumed in the costs for the ISO and the PX. (TURN/UCAN Direct. Test., Exh. 63 at pp. 4-5.) These costs must be identified and removed from the distribution revenue requirements.

2. UDC Consolidated Billing Should be a Tariffed Service Based on the Costs to Provide the Service, and Costs Should be Recovered Only From ESPs Who Elect That Option.

Dr. Jaske has testified concerning the need for UDC consolidated billing on behalf of ESPs. (CEC Direct Test., Exh. 56 at p. 8, l. 20-p. 9, l. 12, witness Jaske.) The need for UDC consolidated billing is undisputed on the record.[4] Dr. Jaske also testified that terms and conditions of UDC consolidated billing must be subject to CPUC oversight resulting in a tariffed service offering. (Id.; see also Tr. Vol 13 at p. 1659.) The CPUC should direct that tariffed UDC consolidated billing options for each utility be developed in the tariff phase of this proceeding.

3. The Monopoly Functions of the UDC Must be Defined and a Separate Revenue Requirement Must be Developed Based on the Costs of Providing Those Services.

As discussed above, one of the purposes of this proceeding is to determine what activities and associated costs should be allocated to the broader functional areas. In order to accomplish this task, it is necessary to identify those activities. The factual record in this case does not provide a sufficient basis for making such a determination.

The CEC maintains that it is critical to define the various activities, identify the associated costs and, determine which of these are monopoly services. (CEC Direct

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[4] Some parties may contend that UDC consolidated billing is an unbundling issue. Consolid UDC billing is more appropriately categorized as a unique utility service offering to facilitate the development of direct access markets.

Test., Exh. 56 at p. 16, ll. 16-24, witness Kristov.) Only these monopoly services should be included within the distribution function; only the costs associated with those monopoly services should be included in distribution rates. (Id.) This exercise should result in the development of a new revenue requirement based on the activities the utility will be performing on behalf of all distribution customers.

It is not possible to develop a new distribution revenue requirement for each utility before January 1, 1998. Of necessity, the revenue requirements that will be in place on January 1, 1998 will be based on an arbitrary division of the existing revenue requirement. There is sufficient time in the transition period, however, to conduct the appropriate analysis to develop a new revenue requirement well before the end of the transition period. This new revenue requirement can be used in two ways. First, to ensure that rates that will go into effect after the transition period are based on the costs of the services. Second, the January 1, 1998 revenue requirements can be adjusted retroactively as soon as the costs studies are complete, without affecting rates.

4. The Optional Non-monopoly Services Offered by the UDC Must be Defined and the Costs of Each Service Offering Must be Determined.

Although unbundling of "revenue-cycle" services is being considered in a separate track, it important for the CPUC to understand that any competitive UDC service offerings will require unique ratemaking treatment, beginning with defining and costing those services and ensuring that the costs for those services are collected only from those who purchase those services.

5. Accurate Dynamic Load Profiles Should be Developed For and Associated Costs Should be Collected Only From Non-Interval-Metered Customers.

The CEC and the Office of Ratepayer Advocates (ORA) have advocated that accurate load-profiles for homogenous customer groups be developed for all non-interval-metered customers. (CEC Direct Test., Exh. 56 at p. 26, l. 4-p.30, l. 11, witness Jaske.) (ORA Direct Test., Exh. 41 at p. 32, l. 1-p. 37, l. 14, witness Price and Appendix I, witness Enderby.) The CPUC has generally regarded load-profiling as a direct access issue. (See e.g. Administrative Law Judge's Ruling on Schedule, Scope, and Other procedural Matters of January 31, 1997 at 3.) It is not. Both Dr. Jaske and Dr. Price testified to the importance of dynamic load profiling for the development of accurate hourly UDC load bidding into the PX. (Id.) We will not repeat that discussion here.

The CEC urges the CPUC to ensure that utilities have the revenues to develop accurate load profiles, and that the costs be recovered solely from customers without real-time meters, (both UDC and direct access customers). The load-profiling workshops called for in the draft direct access decisions should be used to develop a dynamic load profiling methodology for all non-interval-metered customers. (Administrative Judge Wong's Revised Draft Direct Access Decision, Ordering Paragraph 7, p. 91; President Conlon's Alternative Draft Direct Access Decision at Ordering Paragraph 6, p. 85.)

IV. REVENUE ALLOCATION AND RATE DESIGN

A. Comments Common to All Applicants

Subsections 1-2 concern revenue requirements and cost recovery issues that must be resolved before January 1, 1998. Subsections 3-4 may be deferred, but must be resolved before the end of the transition period.

1. Hourly Rate Options for Virtual and Direct Access Customers.

The utilities' proposals do not include an hourly rate option that would provide customers with an opportunity to reduce their electricity bills by responding to real time prices, shifting their use of energy from high cost to low cost hours of the day.

(PG&E Direct Test., Exh.1 at p. 4-8, l.10-p. 7, witness Pease; SCE Rebuttal Test., Exh. 7 at p. 66 l.16-p. 68, l. 11, witness Jazayeri; SDG&E Rebuttal Test., Exh. 10 at p. 16, l.6-p. 17, l. 13, witness Jazayeri.) The utilities assert that the "rate-freeze" imposed by AB 1890 combined with collection of the CTC as an hourly residual results in no meaningful savings from a virtual direct access option during the transition period while CTC is collected. (Id.)

Each utility will base the non-CTC energy charge on the PX price. (PG&E Direct Test., Exh.1 at p. 4-8, l.10-p. l. 7, witness Pease; SCE Direct Test., Exh. 12 at p. 7 ll.1-18, witness Fielder; SDG&E Direct Test., Exh. 8 at p. I-12, l. 23-p. I-13 l. 25, witness Fielder.) The utilities propose to calculate the CTC residually as the difference between the applicable capped rate (June 10, 1996 rates, less 10% for residential and small commercial) and the sum of distribution, transmission, energy, public purpose and any other non-bypassable charges. (PG&E Direct Test., Exh.1 at p. 4-4, ll. 7-14, witness Pease; SCE Direct Test., Exh. 12 at p. 6, ll.1-23, witness Fielder; SDG&E Direct Test., Exh. 8 at p. I-6, l. 23-p. I-7, l. 6, witness Hansen.) The utilities propose to calculate CTC on an hourly basis for customers with real-time meters; for any given hour, hourly-metered direct access customers will pay the same hourly CTC that hourly-metered UDC customers pay. (PG&E Direct Test., Exh.1 at p. 4-6, ll. 3-7 (inferred), witness Hansen; SCE Direct Test., Exh. 12 at p. 7, ll. 1-25, witness Fielder; SDG&E Direct Test., Exh. 8 at p. V-5, ll. 12-28, witness Fielder.) PX energy charges for direct access customers will be shown as a credit on their UDC bills. (Id.) (UDC and direct access customers without real-time meters will have their PX and CTC credits or charges calculated on the same averaged basis through the use of load profiles. They will not see hourly prices at all. (See e.g. SDG&E Direct Test., Exh. 8 at p. I-12, l. 23-p. I-13, l. 25, witness Hansen.)

Because of the hourly CTC calculation the total hourly price for utility services will not vary under the utilities' proposal and UDC customers will have no incentive to shift their energy usage patterns to low cost hours of the day, the virtual direct option mandated by D. 95-12-063 would be meaningless during the transition period. (CEC

Direct Test., Exh. 56 at p. 7, ll. 3-7, witness Jaske; Southern Energy Retail Trading and Marketing (Southern), Direct Test., Exh. 39 at p. 2, ll. 16-24, p. 3, ll.8-10, witness Muller ("Real time pricing information without actual real time pricing does nothing to motivate a consumer to shift load to less costly periods."); ORA Direct Test., Exh. 41 at p. 25, ll.15-26, witness Price.) Even the utilities acknowledge this fact. (See, e.g. SDG&E Rebuttal Test., Exh. 10 at p. 17, ll. 10-13, witness Hansen.)

For direct access customers with real-time meters, not only is there no incentive to use energy at low cost times of the day, the utilities' proposal creates an incentive for these customers to shift as much load as possible from low cost to high cost hours of the day. As stated by Southern witness Mr. Muller: "If the CTC component of [a customer's] electricity cost is calculated as the difference between the tariff energy charge and the PX generation price each hour, the [direct access] customer's total cost (generation, CTC transmission, distribution and public purpose program) is highest when the PX price is lowest. With the Utilities' hourly pricing proposal, the [direct access] customer has an incentive to schedule . . . [his use of energy] during the period when the demand for electricity (reflected in the PX price) is the **highest**, because the CTC component during that time will be at its lowest." (Southern, Direct Test., Exh. 39 at p. 3, ll. 26-33, witness Muller (discussion assumes the customer is paying a fixed price per energy to his supplier) (underscoring added).)

These unacceptable incentives were also revealed through the consideration of two extremes. If the PX price is zero,[5] the direct access customer with a real-time meter will be charged the full amount of the capped rate (since there will be no PX energy charge to credit) in addition to what ever he owes his private supplier. (Tr. Vol. 8, p. 1055, (PG&E witness Pease.) At the other extreme, it is also possible for the PX price to meet or exceed the available head-room for that hour, resulting in zero CTC if the PX energy price is equal to the available head-room and a negative CTC when the PX

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[5] Below the CEC takes issue with the utilities' proposal to reflect a zero non-CTC energy charge during over generation conditions. There should be a positive PX-related energy charge for all hours of the day regardless of whether the CTC is calculated and charged on an hourly basis.

energy charge exceeds the available head-room. (ORA Direct Test., Exh. 41 at p. 26, l. 20-p. 27, l. 4, witness Price.) PG&E acknowledges this possibility noting that subtractive approach could "result in utility bills that are less than or equal to zero . . ." if the PX energy charge is high enough that the resulting negative CTC would cancel out all the other rate components. (PG&E Direct Test., Exh.1 at p. 4-6, fn. 7, witness pease (proposing that in such cases, the minimum utility bill be equal to zero).)

The CEC, ORA and Southern support the residual approach to calculating CTC, but oppose the utilities' proposal to calculate and charge CTC on an hourly basis: it is this hourly feature that results in the "perverse" price signals noted above. (Tr. Vol. 10, p. 1282, ll. 1-10, witness Muller.)

Southern and ORA offer solutions that retain the residual calculation of CTC based on June 10, 1996 rates, but reject calculating and charging CTC on an hourly basis. Rather, Southern proposes "to calculate the CTC each month based on the actual class average Power Exchange prices and use that fixed CTC . . . as the basis for charging . . . CTC . . . for all customers within that rate class." (Id. at p. 1259, ll. 13-17.) ORA also proposes to use an average CTC. Specifically, ORA proposes to use a "rolling average for each [time-of-use] TOU period in the customer's billing period, based on the customer's otherwise-applicable tariff's CTC rate (which in turn are based on a rolling average PX cost and schedule-specific load profile). The rolling average CTC rate should be based on the loads of all customers subject to the same otherwise-applicable tariff, whether or not hourly meters are installed on their premises." (ORA Direct Test., Exh. 41, witness Price at p. 26, ll. 8-12.)

The CEC supports the concept of using an averaged CTC as recommended by Southern and ORA. Development of the details, such as whether it should be a rolling or monthly average, should be deferred to the tariff phase of this proceeding. This approach is consistent with the CEC's recommendations with the exception that the CEC proposed a cost sharing mechanism whereby PX energy costs saved as a result of customers shifting load would be shared between the customer and the utility in order to make the virtual direct access option more attractive to the utilities while providing customers with the opportunity to reduce their utility bills.[6] (CEC Direct Test., Exh. 56 at p. 7, l. 25-p. 6, l. 2, Tr. Vol. 13, p. 1652, l. 22-p. 1654, l. 5, witness Jaske.) The CPUC should order the development of virtual and direct access tariffs in the tariff phase of this proceeding based on an averaging methodology that will result in real-time metered customers seeing an hourly CTC charge that does not vary over the hours of the day. As discussed below, these tariffs are allowed by AB 1890, are required by D. 95-12-063, will not jeopardize, and will in fact enhance, the utilities opportunity to collect CTC during the transition period (even without a cost sharing mechanism). Further, they will provide customers with many opportunities to respond to hourly energy prices that are not available through existing time-of-use (TOU) tariff options.

a. **AB 1890 Allows Meaningful Hourly Rate Options**

The utilities rely on the "rate-freeze" and the anti-cost-shifting provisions of AB 1890 in support of their position that AB 1890 precludes a meaningful hourly rate option. According to SCE witness John Fielder, AB 1890 prohibits both increases and decreases in rates in effect on June 10, 1996, except for the 10% rate reduction applicable to residential and small commercial customers. (Tr. Vol. 2 at p. 271, ll. 4-7.) SCE relies on Cal. Pub. Util. Code § 368(a),[7] which provides that the utility cost recovery plans "shall set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996 . . . " (except for the 10% rate reduction applicable to residential and small commercial customers) for this conclusion. (SCE Direct Test., Exh. 12 at p. 5, ll. 15-17, witness Fielder.)

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[6] As discussed below, however, other evidence establishes that cost sharing is not necessar provide utilities with greater opportunity to fully collect CTC.

[7] All statutory references are to the California Public Utilities Code unless otherwise indicated

AB 1890, however, does not expressly prohibit rates from going down. For example, § 368(a) specifies that the rate reduction must be "no less than 10%," suggesting that the 10% is the minimum rate reduction possible. In addition, § 330(v) requires the utilities to collect CTC "in a manner that does not result in an increase in rates to customers of electrical corporations . . .," suggesting that rates may not go up, but can go down. See also § 367(e)(2) (no rate increase as a result of allocation of transition costs).

More importantly, § 378 expressly provides that the CPUC may authorize "new optional rate schedules and tariffs, including new service offerings, that accurately reflect the loads, locations, conditions of service, cost of service, and market opportunities of customer classes and subclasses." Thus even if AB 1890 "freezes" June 10, 1996 rates (except for the 10% rate reduction) for all rate options in effect as of that date, AB 1890 also expressly allows for the creation of optional rate schedules. The optional hourly rate option outlined above falls squarely within the definition of § 378.

(i) **<u>Utility Reliance on Section 367(e)(1) is Misplaced</u>**

Section 367(e)(1) requires the CTC "to be allocated among the various classes of customers, rate schedules, and tariff options to ensure that costs are recovered from these classes, rate schedules, contract rates, and tariff options . . .in substantially the same proportion as similar costs are recovered as of June 10, 1996, through the regulated retail rates . . . ." (See e.g. SCE Direct Test., Exh. 12 at p. 6, ll. 1-14, witness Fielder). As a threshold matter, we note that CTC was not an element in rates on June 10, 1996, although various cost items that will be included in the CTC were also cost elements included in June 10, 1996 rates. Moreover, some of these costs will be accelerated, others amortized and some may even be deferred, as compared to the proportions of these costs in June 10, 1996 rates.

Nevertheless, it is apparent that the utilities' proposals to calculate and charge CTC on an hourly basis fails to satisfy this proportionality requirement. As discussed above, a customer with a real-time meter (either virtual or direct access) who uses substantial amounts of energy in off-peak hours, and relatively small amounts of energy in on-peak periods, will contribute many more dollars to offset CTC than a customer who uses substantial amounts of energy in on-peak periods and relatively small amounts of energy in off-peak periods. Thus, customer contribution to CTC will vary from customer to customer within rate classes, and clearly will not be collected from customers in any kind of proportion, let alone the proportion in effect on June 10, 1996. Further, if customers within classes are not paying proportionately the same CTC, there is no way to determine, let alone ensure, that CTC is being allocated proportionately among customer classes, rate schedules etc.

On the other hand, an averaged CTC, could be designed to ensure that customers' contribution to CTC within their respective class was proportional, in some meaningful way, and provide a basis for customers with real-time meters to lower their bills by shifting their energy use to lower cost hours of the day. This approach would therefore go much further in satisfying § 367(e)(1) than the utilities' hourly proposal.

(ii) **<u>Utility Reliance on § 368(b) is Misplaced</u>**

Section 368(b) applies to the utilities' cost recovery plans. It requires the separation of rate components into energy, transmission, distribution, public benefit programs, and CTC "to ensure that customers of the electrical corporation who become eligible to purchase electricity from suppliers other than the electrical corporation pay the same bundled component charges, other than energy, a bundled service customer pays. No cost shifting among customer classes, rate schedules, contract, or tariff options shall result from the separation required by this paragraph . . . ."

There are two sentences of this quoted provision. The first sentence suggests that direct access customers pay the same charges, "other than energy," a bundled service customer pays. Because the utilities' proposal distinguishes between real-time metered and load profiled customers, their proposal does not result in direct access customers paying the same charges, "other than energy" that a bundled service customer pays. The utilities propose to treat real-time metered customers differently from load-profile customers. Real-time metered customers (direct access or UDC) will pay the same hourly CTC. Load profiled customers (direct access or UDC) will pay the same averaged CTC. But real-time metered direct access customers will not pay the same CTC as UDC load profiled customers (or direct access load profiled customers). The CTC averaging methodology recommended above, treats all customers the same. Each customer will face the same CTC responsibility, although real-time metered customers will see an hourly CTC component.

The second sentence prohibits cost shifting. The utilities proposal does not prohibit and actually creates an incentive for cost shifting. As discussed above, under the utilities' hourly CTC proposal, real-time metered direct access customers who can shift their load can reduce their CTC liability by using energy at high costs times of the day and avoiding use of energy during low cost times of the day. On the other hand, real-time metered customers who must use energy at low cost times of the day, and cannot shift their usage to high cost times of the day, will pay a much larger share of CTC. Under the utilities' proposal, virtual direct access customers will be indifferent to the time of day they use energy and will, presumably use energy based solely on their own convenience. Using an average CTC will avoid these perverse incentives and create appropriate incentives.

b. The CPUC Policy Decision Requires Development of a Virtual Direct Access Option That Provides Customers With An Opportunity to Lower Their Energy Bills

One fundamental feature of the CPUC's December 20, 1995 Preferred Policy Decision, D. 95-12-063, is real-time energy pricing. That decision requires distribution utilities to "offer an optional tariffed electric service which references the appropriate real-time market-clearing price." (D. 95-12-063 (mimeo) at 77. See also Ordering paragraph 11 of D. 95-12-063 (each UDC must offer "tariffed electric service which references the real-time market clearing price as published by the Power Exchange").) This requirement is based on the CPUC's finding that

> revelation of the real-time price of electricity coupled with a rate alternative that allows the customer to respond intelligently will produce savings for any customer who is able to shift demand from peak to off-peak hours. The potential that many customers will respond to this opportunity to take significant control over the cost of their consumption will produce a collective benefit, in that demand will be redistributed away from the current peaks. Future generation demands will be forestalled even as existing investments in generation are made more productive. The result is a triple win, embracing the individual consumer of any class who is able to reduce costs by shifting load, the society at large which defers the demand for new generation, and investors in existing plant and equipment who see it put to more productive use.

(D. 95-12-063 (mimeo) at 77-78; see also Finding of Fact 17.)

Moreover, Administrative Law Judge Wong's revised draft direct access decision (mailed April 11, 1997) describes the hourly rate option as allowing "individual consumers to participate in the PX market by providing them with the **opportunity to reduce their electricity bills by responding to real time prices**." (Revised Draft Decision at 33 (emphasis added).) The draft decision defers the development of such an hourly PX rate option to this proceeding. (Id.) An hourly rate option that does not provide an opportunity for consumers to lower their bills is not an hourly rate option at all and is inconsistent with D. 95-12-063.[8]

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[8] President Conlon's draft alternative direct access decision also describes the hourly rate op as allowing customers to achieve savings by shifting load. (President Conlon's Alternative Decision on direct access (mailed April 17, 1997) at 29). This decision notes that the issue of whether "the rate freeze prohibits any actual bill savings from occurring" is an issue in this

c. **Direct Access Customers With Real-time Meters Should Also Have Appropriate Incentives**

As discussed above, the utilities' hourly CTC proposal creates an incentive for real-time metered direct access customers to use energy during high cost hours and to avoid, or minimize the use of energy during low cost hours of the day. Charging all customers with an hourly CTC calculated as the average of the monthly residual determination treats all consumers similarly and provides real-time metered customers with proper price signals.

d. **Hourly Rate Options Will Not Jeopardize, and Will, In Fact, Enhance the Utilities' Opportunity to Recover CTC**

The utilities offer two examples where using the average CTC would appear to yield a less-than-desirable result compared to the utilities' hourly CTC proposal. In one example, Dr. Jazayeri testified that if customers, who already have a better-than average energy use pattern when compared with the load profile for their customer class, take advantage of an hourly rate option with an average CTC, "cherry-picking" would result and utilities would collect less CTC. (SCE Direct Test., Exh. 7 at p. 68, ll. 20, witness Jazayeri.) On cross-examination, Dr. Jazayeri acknowledged that his example also included the assumption that customers would not change their energy consumption patters. (Tr., Vol. 11 at p. 1466, l. 27-p. 1467, l. 19.) Dr. Jazayeri did not analyze the impact on total CTC collection if customers (whether better than average, average or worse than average) modified their behavior and shifted some portion of their energy use from high cost to lower cost hours of the day, although, during cross-examination, he acknowledged the possibility that more CTC would be available if customers shift load to lower PX energy cost periods. (Id. at p. 1467, l. 20-p. 1468, l. 5.) Nor did Dr. Jazayeri analyze the incentives of real-time metered direct access customers to use energy at high PX price times of the day, and to avoid or minimize energy use at low priced hours, although Dr. Jazayeri acknowledged that these customers would receive no energy credit on their utility bills when the PX price

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proceeding. (Id.) As discussed in this brief, AB 1890 does not preclude meaningful hourly rat options during the transition period.

were zero. (Id. at p.1471, ll.7-15.)

Mr. Muller, expert witness for Southern, did analyze the effect of customers shifting load and concluded that if the PX price were reduced by an "average of only $0.00037 per kWh (or 1 mill per kWh for 322 hours per year)," as a result of shifting load, the utilities would be indifferent to using average PX prices for purposes of calculating CTC. (Southern, Direct Test., Exh. 39 at p. 7, ll. 4-8, witness Muller.) It follows that any further average PX price reduction would increase the dollars available to offset CTC as compared with the utilities' proposal. Mr. Muller emphatically agreed that the potential for utilities to recover CTC by providing appropriate price signals is much greater using a fixed CTC than under the utilities' proposal. (Tr. Vol. 10 at p. 1265, ll. 4-8, witness Muller.) The CEC's cost sharing proposal provides an even greater opportunity for utilities' to recover CTC and may not be necessary due to the fact that a relatively minuscule shift of energy use would ensure that utilities will be at least as well off when compared to their proposal.

In another example, counsel for SCE presented a hypothetical that, in simplified form, involved a customer with an average energy cost of 2.5¢ per kWh compared to the average customer within his rate class, who has a 3¢ per kWh average cost; customers in the rate class pay a total average of 5¢ per kWh energy charge, with the 2¢ difference applied to CTC. (Tr. Vol. 13 at p. 1653, l. 22-p. 1653, l. 12.) With this hypothetical, SCE sought to demonstrate the possibility that a customer could enter into a direct access contract for 2.6¢ per kWh, and pay total energy charges of only 4.6¢, thereby achieving total savings of .4¢ per hour compared to the bundled UDC customer; but he would be paying higher energy charges and lower CTC than he would have paid had he remained a fully-bundled customer, an economically inefficient result. (Id.) As Dr. Jaske responded, the most economically efficient option for this customer would be the virtual direct access option, which would equal 4.5¢ per kWh hour in this example (which does not include the CEC's cost sharing proposal). (Id. at p. 1656, ll. 1-7.) Dr. Jaske also testified that he did not consider low energy cost customers taking advantage of such hourly rate options as "cherry-picking" since what customers pay should be based on the cost to serve them. (Id. at p. 1657, ll. 5-13 (purpose of restructuring is to get away from cross-subsidies within customer classes).) Moreover, as discussed above, a minuscule average PX price reduction caused by load shifting will make up for this so-called cherry-picking problem. Of course, customers might make the "wrong" decision and pay a higher per hour energy charge to a private ESP than he would have had to pay had he chosen to be a virtual direct access customer. He is unlikely to know this until after the fact, however. Moreover, it may be more important for that customer to have a fixed priced energy contract than to bear the risk of PX price volatility. (Of course the customer could have a contract-for-differences with an ESP for 2.6¢, with the same economic consequences to the parties.)

e. **Existing TOU Options Do Not Offer the Triple Win Afforded by Real Time Pricing**

The utilities assert that existing TOU options will result in the "triple win" that the CPUC has determined will be afforded by real-time pricing. Real-time pricing information with real-time price options is the foundation of the new market structure. If existing TOU options were sufficient to achieve the "triple win," there would be no purpose for developing an hourly system. Real-time pricing options will create numerous opportunities not afforded by existing TOU options.

For example, each utilities' residential TOU schedule divides the day into two large blocks, on-peak (roughly between noon and 6:00 p.m.) and off-peak (all other hours of the day). (See, e.g. Tr. Vol 8, p. 1063 ll. 10-20, PG&E witness Pease.) Although no one can predict how much the PX price will vary from hour to hour, historically, energy costs within these large blocks have varied considerably depending on the circumstances. (Id.) Under existing TOU rates, customers have no incentive to modify their behavior within the time-blocks, yet the time-blocks do provide incentives for major shifts at the transition hours between blocks out of all proportion to the actual cost of generation. (Tr., Vol. 13 at p. 1664, ll. 10-28, CEC witness Jaske.) Hourly prices create much more opportunity for customers to respond by shifting load away from comparatively high-cost hours to comparatively low-cost hours. Moreover, customers have varying ability to shift load from the on-peak to the off-peak block. Hourly price-signals provide opportunities at all hours of the day and are directly linked to the hourly PX situation, which did not exist when integrated utilities developed TOU rates.

2. PX Energy Charge in Over Generation Conditions

As noted above, each utility will base the non-CTC energy charge on the PX price. However, it is commonly acknowledged that for some hours, due to "must-take" QF energy and "must-run" energy, there may not be sufficient demand to be met in the PX due to "over generation" conditions for the PX to yield a market clearing price. (Tr., Vol. 8, p. 1051, l. 23 - p. 1053, l. 28, witness Pease.) During those hours, the PX price will be zero. (Id.)[9] Of course, "must-take" and "must-run" energy must be paid for as specified by the applicable QF and ISO contracts. (Id.) PG&E, for example, proposes to add these costs to the CTC. (Id.) Thus for any hour that the PX fails to yield a market-clearing price, there will be no energy charge. Yet the costs of the energy incurred by the utilities to pay for QF energy will be added to the CTC account as a debit. The difference between the capped-rates and the sum of distribution, transmission, public purpose and other non-bypassable charges, will be credited, in these circumstances, 100% to CTC.

The CEC maintains that reflecting a zero energy charge when energy is not in fact available at zero cost sends a highly inappropriate signal to all consumers and creates dramatically perverse incentives for all customers (both direct access and

[9] Exactly how often this may occur is subject to debate.

virtual direct access) with real-time meters.[10] For the reasons discussed below, the CEC urges the CPUC to adopt a default energy price during the transition period while CTC is being collected. The CPUC should consider basing that default energy price on the lowest PX market clearing price of the most recent 24 hour period. In this way the default energy price will bear a close relationship to the PX price, regardless of the price of QF and must-run energy. (The difference could then be appropriately added as a debit to the CTC account.)

a. **Customers Without Realtime Meters**

Although customers without real-time meters may never see a zero energy charge on the bill because the energy charge will be averaged over the billing period, they will see artificially low energy prices. This will have a deleterious effect on the development of competitive energy markets. Fully-bundled UDC customers will be the least affected, since their overall rate will remain capped per AB 1890. Nevertheless, artificially low PX energy prices will skew the comparison between PX and direct access energy options because private energy services providers will have to compete with artificially low PX energy prices, if direct access customers are only credited with the PX energy costs. Moreover, because direct access customers will not be receiving an energy credit and will be paying for must-take energy as CTC, they will be shouldering a disproportionately greater CTC burden than fully-bundled customers. These consequence are likely to reduce the attractiveness of direct access options to fully-bundled UDC customers.

b. **Customers With Realtime Meters**

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10 This issue only affects the transition period. Once QF contracts have expired, and assumir "must-run" energy charges are included in some other bill component, such as transmission charges, a default energy price will no longer be necessary. It will still be possible for there to zero market clearing price as a result of generators bidding zero to the PX. Under these circumstances a zero energy charge would be appropriate for those hours.

Customers with realtime meters will see a zero PX charge, under the utilities' proposals, for those hours in which the PX is in an over generation state. UDC customers will see their energy charges reflected only as CTC equal to the entire amount of available "head-room" up-to the applicable capped rate. These customers will have no information about what energy actually costs during those hours, although they will be paying for QF energy through CTC charges.

The consequences to the direct access customer with a realtime meter are dramatic. During hours the PX fails to clear, there will be no energy credit for these customers. These customers will incur UDC charges identical to the virtual direct access customer, i.e. the applicable capped-rate because there will be no energy credit. In addition, they will be responsible for energy charges, and any other associated charges, owed to their private ESP (assuming a fixed hourly energy rate). (Tr. Vol. 8 at p. 1054, l. 17-p.1055 l. 25.)[11] These customers will end-up paying more CTC than the comparable virtual direct access customer (or full-service customer) for these hours, because they will be getting no energy credit while incurring CTC liability to pay for must-take and must-run energy. Using a reasonable default energy price during the transition period will solve this problem.

3. Initiate New PBR Proceedings for Each Utility

It is essential that new PBR proceedings be initiated to develop separate revenue requirements for the monopoly and the various non-monopoly services of the UDC. Because the UDC will be offering non-monopoly services, such as PX energy, and because other UDC services may become competitive, a new PBR structure that accommodates UDC provision of monopoly and non-monopoly services must be in place. (See CEC Direct Test. Exh. at pp. 11-13, witness Jaske, for a general discussion of PBR principles that the CPUC should consider.)

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[11] This feature, plus the utilities' hourly CTC proposal, will further enhance the real-time mete direct access customer's incentive to shift energy use to high-cost times of the day in order to receive large energy credits and reduce CTC liability.

Current PBR structures will not accommodate the UDC or the distribution function becoming smaller. For example Dr. Jaske testified that SCE has a "base-rate escalation mechanism with adjustment for productivity and other factors." (Tr. Vol. 13 at p. 1649, ll. 9-10.) This means that revenue requirements and rates cannot go down even though the scope of utility responsibility shrinks. Notwithstanding the recent adoption of D. 96-09-092, SCE's current PBR framework is simply not designed to respond to changes in the scope of responsibility and the provision of services other than a fixed basket of services. (Tr. Vol. 13 at p. 1649, ll. 9-20.)

The new PBR framework must include a mechanism to ensure that monopoly revenues do not subsidize the non-monopoly services. It should also include incentives for UDCs to develop accurate load bids on behalf of UDC energy services customers, which in turn requires accurate load profiles.

Unfortunately, the CPUC recently issued decision on distribution, PBR, D. 97-04-067. This decision modifies the existing requirement that each utility file an application for a distribution PBR by vacating this requirement as to SCE. (The filing requirement remains in effect for PG&E and SDG&E.) The CEC urges the CPUC to reconsider its decision as to SCE in light of the record in this proceeding. Before the utilities file their applications, it is advisable for the CPUC to first define the roles and responsibilities of the UDC and then to provide the utilities with guidance concerning the rate-design PBR principles that are appropriate for the new UDCs. Work to clarify these issues should begin immediately so that utilities can receive this guidance to assist them in preparing their applications, now scheduled for late 1997.

4. Seek Legislative Approval to Redesign How to Provide Affordable Electricity to Residential Customers so That Rates for all Customers Can be Consistent With Economic Efficiency

The transition period also affords the opportunity to consider replacing the current base-line allowance mechanism and put in place a rate structure with prices that reflect the costs of service. (CEC Direct Test. Exh. at p. 5, l. 10-p. 6, l.16, witness Jaske.) Means-tested subsidies provided directly to the needy customer can be used to ensure all customers have affordable electricity without affecting the rates that customers see. (Id.) The CEC realizes that the current inverted block design is mandated by statute. Such a rate design, however, is not consistent with economic efficiency or cost pricing and cannot be continued in the restructured electricity market. The CEC urges the CPUC to recommend to the legislature that: (1) Cal. Pub. Util. Code § 739 be repealed to allow for the comprehensive rate design revisions consistent with the restructured industry; and (2) a means tested subsidy scheme be authorized in its place.

V. MASTER METER ISSUES

The CEC has not addressed the master meter issues litigated in this proceeding.

VI. BILL FORMAT

A. Comments Common to All Applicants

Each utility is subject to the requirements of AB 1890. The CPUC has jurisdiction to impose additional requirements. (In addition, the utilities should have the ability to develop custom bill formats, provided the associated costs are charged only to those customers who desire specialized bill formats.)

As discussed below, the following items of information should be provided to customers on bills or bill inserts beginning January 1, 1998[12]:

(1) Energy charges separately identifying: PX charges, the energy imbalance

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[12] Although the utilities have, apparently, varying ability to include information as line items on bills themselves, it is undisputed that information that may not be possible to include on the bi be provided to consumers in the form of bill inserts.

settlement costs, UDC energy-related costs, CTC charges and the nuclear decommissioning charge;

(2) Transmission;

(3) Distribution;

(4) Non-bypassable surcharges, separately identified;

(5) Other information including: average peak and off-peak energy prices; self-comparison and other-customer comparison information.

Section 392 is the relevant provision of AB 1890. It provides in pertinent part:

(b) It is the intent of the Legislature that . . . electricity consumers be provided with **sufficient and reliable information to be able to compare and select among products and services provided in the electricity market**, . . . [Emphasis added.]

(c) (1) Electrical corporations shall disclose each component of the electrical bill as follows:

(A) The total charges associated with transmission and distribution, including that portion comprising the research, environmental, and low income funds.

(B) The total charges associated with generation, including the competition transition charge.

The CEC maintains that § 392 requires each charge itemized in (A) and (B) above, plus any other information determined to be necessary to provide customers with **sufficient and reliable information to be able to compare and select among products and services provided in the electricity market**, be provided to customers on a monthly basis. All items should be identified separately either on the bill or in a bill insert. All variable items, such as energy and CTC should be reflected in separate line items on the bill itself.

Utility proposals, that lump transmission, distribution, research, environmental and low income funds together, and lump generation and CTC together, fail to provide consumers with **sufficient and reliable information to be able to compare and select among products and services provided in the electricity market**. This is most obviously apparent with respect to lumping energy and CTC together. The non-CTC energy charges must be separately, and plainly identified in order for customers to be able to compare UDC energy offerings with those available from private energy services providers. Moreover, the PX energy charge should itself consist of two separate components: the costs of the load bid into the day-ahead and hour-ahead markets and the energy imbalance settlement costs. (CEC, Direct Test., Exh. 56 at p. 23, ll. 17-26, witness Jaske.) In addition, the UDC energy-related charges should be separately identified, as discussed above. This information is necessary for customers to compare the accuracy of UDC and private energy services providers' ability to keep settlement costs as low as possible, as a result of accurate load forecasting, for example. Further, there should also be some indication of peak versus off-peak generation costs. (Id.) This information will facilitate customer choice of hourly or TOU rate options. Finally, the nuclear decommissioning charges should also be separately identified: it is an energy charge but should not be lumped with the PX energy charges, because it is non-bypassable. Similarly, it should not be combined with CTC because § 379 provides that nuclear decommissioning charges should be a separate non-bypassable charge distinct from CTC.

Similarly, transmission and distribution should be separately identified. Some customers may be able to by-pass the distribution system, by taking service at the transmission level or through another distribution company. Although the various public purpose program surcharges are non-bypassable, this information also provides customers with a basis for purchasing services. For example, based on this information, customers may conclude that environmental programs are not being sufficiently supported, and therefore choose to enter in to a contract with green energy services provider so that more dollars are diverted to green power projects.[13]

Other information not expressly identified in § 392 but which nevertheless is necessary to allow customers to select among energy products and services includes information concerning how the customer's energy usage compares with his own prior usage ("self-comparisons"), and with other similarly situated customers ("other-customer comparisons"). (CEC, Direct Test., Exh. 56 at p. 22, ll. 1-11, witness Jaske.) This information is critical to helping customers decide whether to seek an alternative energy provider in order to reduce costs or add services, including energy efficiency products and services. (Id.)

This information should be provided to customers on bills, or in bill inserts, beginning January 1, 1998. However, accurate other comparison information, which would ideally be based on a set of common shared factors, such as climate zone, home appliances and size and style of structure, i.e. the kind of information that would be used to create more accurate load profiles, may not be available as of January 1, 1998. Nevertheless, customers can be provided with a comparison of how their own energy use compares to the load profile for the applicable customer class that is currently in use. As new load profiles are developed, which should be done quickly, customers should receive information comparing their use with the average to serve customers subject to the new load profile.

One final bill format issue concerns the 10% rate reduction applicable to residential and small commercial customers required by AB 1890 (§ 368(a)). That rate reduction will be financed through the issuance of "rate reduction bonds" to finance a portion of

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[13] Parties, such as TURN/UCAN, urge that utilities be required to identify the source and percentage of types of generation dispatched by the PX in order to facilitate development of gre markets. (Direct Test., Exh. 63 at p. 20, witness Marcus .) As Dr. Jazayeri testified, this informa could only provided by the PX based on information submitted by the bidders. (Tr., Vol. 1 at p. 9 21-p. 99, l. 11, witness Jazayeri.) The CEC agrees that the information desired by TURN shou available to customers, provided the information is reliable. The CPUC, CEC and interested parties would work with the PX to make this information available, in which case the utilities co include this information as a bill insert.

the CTC. Section 1(b)(3) (preamble to AB 1890); § 840. Accordingly, the 10% reduction should be reflected on customer bills, to the extent possible, as a reduction of CTC and not other rate components.

The CEC comments on each of the utility's bill format proposals in Chapter V of our testimony. (CEC Direct Test., Exh. 56, pp. 21-24.) We will not repeat that discussion here except to note that the CEC agrees with SDG&E that customers be allowed to choose between two types of bill formats, a simple bill format with minimal information and a more detailed bill format. During the transition period, however, the simple bill format should separate the CTC from the other energy charges. SCE's proposal, and SDG&E's simple bill format proposal, are defective in that CTC is not separately identified. (Tr. Vol. 1 at p. 93, l. 4-p. 94, l.14, witness Jazayeri (SCE customer would have to make a calculation to determine what portion of the energy charge was CTC); Tr. Vol. 2 at p. 20, ll. 20-25, witness Hansen, SDG&E customer would see only total energy charges.)

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Respectfully Submitted,

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